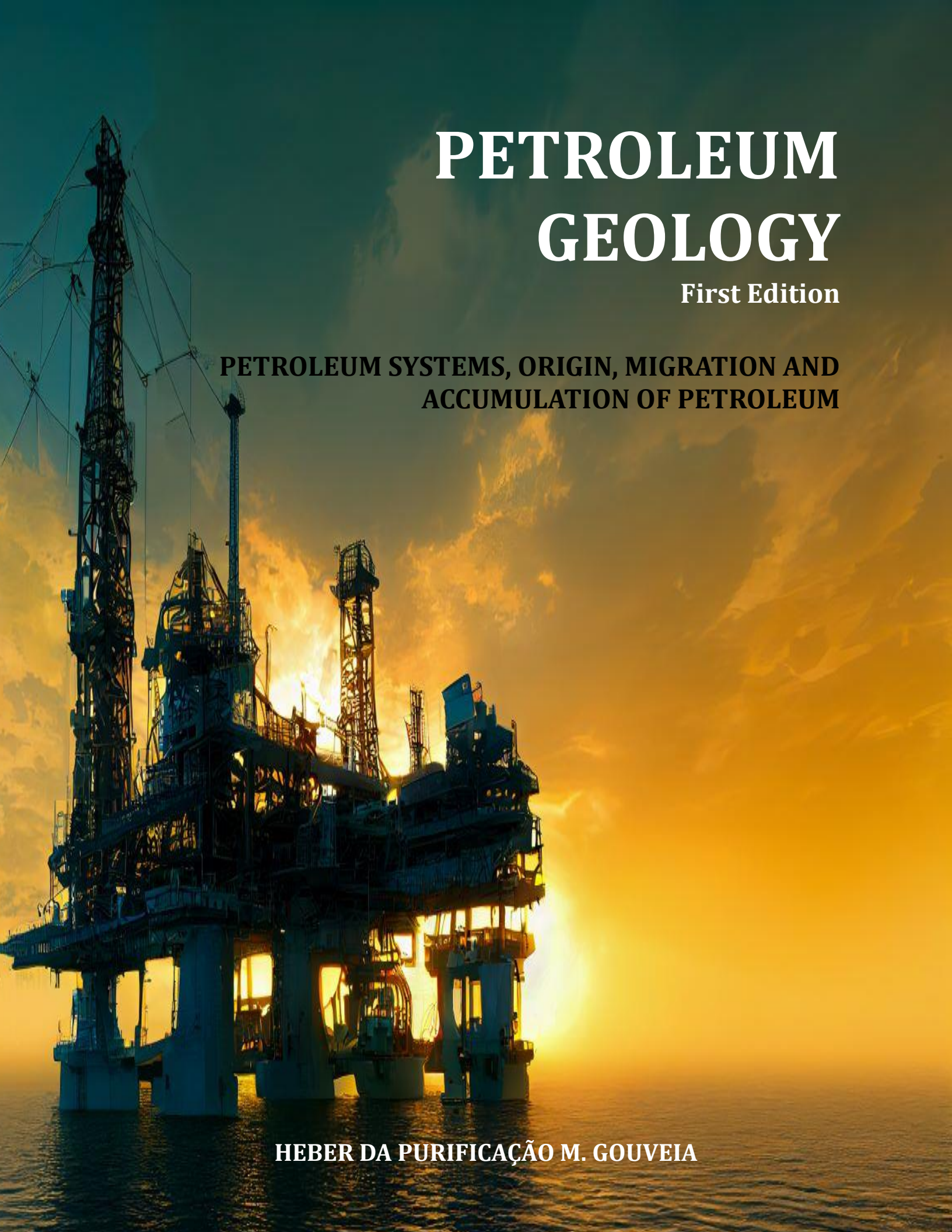

PETROLEUM GEOLOGY

First Edition

PETROLEUM SYSTEMS, ORIGIN, MIGRATION AND ACCUMULATION OF PETROLEUM

HEBER DA PURIFICAÇÃO M. GOUVEIA

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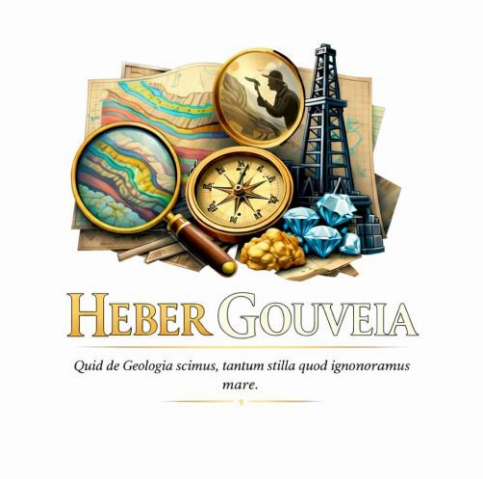

PETROLEUM GEOLOGY

Petroleum Systems: Origin, Migration and Accumulation of Petroleum

Author: *Heber da Purificação M. Gouveia*

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"What we know about Geology is just a drop in the ocean compared to what we don't know."

Heber Gouveia

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1 PETROLEUM GEOLOGY

Petroleum Geology is the area of Geology that deals with the study of the origin, occurrence, movement, accumulation, and exploration of hydrocarbons. It refers to the specific set of geological disciplines that are applied to the search for hydrocarbons (petroleum exploration).

In this book, we will explore the fundamentals of petroleum geology and the role it plays in the petroleum industry. From the origin of petroleum to the geology of its accumulation, we will delve into the various aspects of this fascinating field and understand why it is essential to the energy sector. So, fasten your seatbelts and let's embark on this exciting journey through the world of petroleum geology.

2 PETROLEUM

Petroleum is a complex mixture of hydrocarbons and varying amounts of non-hydrocarbons.

Hydrocarbons are organic compounds formed exclusively of carbon (C) and hydrogen (H). They can occur in three main physical states: gaseous (methane), liquid (light and medium liquid fractions), and solid (natural bitumen).

When the liquid fraction of hydrocarbons occurs naturally in geological reservoirs, it is called oil or crude oil. The term condensate refers to the fraction of light hydrocarbons that occurs as gas in the reservoir, under conditions of high pressure and temperature, and which condenses into liquid when subjected to surface conditions.

The term "natural gas" refers to the fraction of hydrocarbons that occurs predominantly in the gaseous state under natural reservoir conditions, and may be associated with oil or occur independently.

Another form of occurrence of hydrocarbons are gas hydrates, crystalline structures formed by water and gas molecules (mainly methane), which develop under specific pressure and temperature conditions, being more common in polar regions and in deep marine environments.

In the strict sense, petroleum refers to the natural liquid fraction of hydrocarbons accumulated in geological reservoirs. However, in common industrial usage, the term is often used synonymously with hydrocarbons in general.

2.1 Composition of Liquid Hydrocarbons (Petroleum)

Petroleum contains hundreds of different compounds. Studies conducted on oil samples from the Ponca City field (Oklahoma, USA) identified approximately 350 hydrocarbons, 200 sulfur compounds, in addition to various non-hydrocarbons.

In elemental terms, petroleum is essentially composed of carbon (80 to 90% by weight), hydrogen (10 to 15%), sulfur (up to 5%), oxygen (up to 4%), nitrogen (up to 2%), and traces of other elements (e.g., nickel, vanadium, etc.). The composition of petroleum is generally described in terms of the proportion of saturated hydrocarbons, aromatic hydrocarbons, and non-hydrocarbons.

Saturated hydrocarbons, compounds of C and H linked by single bonds, include normal alkanes (normal paraffins or n-alkanes), isoalkanes (isoparaffins or branched alkanes), and cycloalkanes (cyclic alkanes or naphthenes). n-Alkanes with fewer than 5 carbon atoms (methane, ethane, propane, and butane) occur as gases under normal pressure and temperature conditions, while those with 5 to 15 carbon atoms are liquids, and those with more than 15 carbon atoms range from viscous liquids to solids. Most normal alkanes found in petroleum have up to 40 carbon atoms.

Isoalkanes are mainly found in compounds with up to 10 carbon atoms, although they occur with up to 25 atoms. Cycloalkanes can have up to 6 carbon rings, each with 5 or 6 carbon atoms. Iso- and cycloalkanes occur mainly in the liquid state.

Aromatic hydrocarbons are compounds that have an aromatic ring (benzene) and occur predominantly in the liquid fraction of petroleum. They can have more than one aromatic ring, such as naphthalenes (2 rings) and phenanthrenes (3 rings). Toluene, with only one benzene ring, is the most common aromatic compound in petroleum, followed by xylene and benzene.

Finally, non-hydrocarbons are compounds that contain elements other than carbon and hydrogen, called heteroatoms. Since nitrogen, sulfur, and oxygen are the most common heteroatoms, these compounds are generally known as NSOs. The occurrence of metals (especially nickel and vanadium) associated with organic matter in compounds called organometallics is also common.

Resins and asphaltenes are high molecular weight NSO compounds, poorly soluble in organic solvents. Their basic structure consists of layers of condensed polyaromatic compounds, stacked in the form of aggregates.

The proportion of resins and, mainly, asphaltenes in petroleum is directly proportional to its viscosity.

There are basically two types of oil classifications. Those proposed by engineers are based on the composition and physicochemical properties of the oil (density, viscosity, etc.) and are geared towards the areas of production and refining. Classifications proposed by geologists, on the other hand, emphasize composition, focusing on the origin and evolution of petroleum.

Among the geological classifications, one of the most used is that proposed by Tissot & Welte (1978), which divides oils into six types: paraffinic, paraffinic-naphthenic, naphthenic, intermediate aromatic, asphaltic aromatic, and naphthenic aromatic. The composition of each type reflects the origin, the degree of thermal evolution, and the alteration processes to which the petroleum has been subjected.

Although light or heavy oils are often directly compared to the density of water, the industrial classification uses the API gravity, a standardized measure that expresses the density of petroleum relative to water, quantitatively indicating whether an oil is light, medium, or heavy.

2.2 Composition of Gaseous Hydrocarbons (Natural Gas)

Natural gases, in turn, are classified as dry or wet gas. Dry gas is composed essentially of methane, while wet gas also contains ethane, propane, and butane in varying proportions. In addition to hydrocarbons, other gaseous compounds may be associated, such as carbon dioxide (CO2), hydrogen sulfide (H2S), and more rarely, helium (He) and hydrogen (H). Non-

associated gas is that which occurs alone in the reservoir, and associated gas occurs together with the oil.

3 PETROLEUM SYSTEM

Petroleum systems are geological models that unite all the elements and processes necessary for the formation, migration and accumulation of oil and natural gas underground. More concisely, we can define Petroleum Systems as the relationship between the hydrocarbon generation process, migration and hydrocarbon accumulation.

The Petroleum System consists of:

1) Mature Source Rock

• Organic Matter: in quantity and quality. -Thermal Evolution: it has been subjected to high temperatures.

• Types of Source Rocks: schists, marls and calcilutites.

2) Transport Rock/Migration Path - Permeable (all the rock or layer that serves as a "road" for oil to migrate from the source rock to the reservoir rock).

• Types: Porous sandstones and carbonates.

3) Reservoir Rock - Porous and permeable rocks capable of containing and transmitting fluids.

• Capped and trapped.

4) Seal Rock (Label) - Evaporites (salt)

• Low permeability.

• They are part of the trap.

5) Traps

• These are geological structures or configurations in the subsoil (such as faults and folds), consisting of a porous and permeable reservoir rock, covered by an impermeable seal rock, which prevents the upward migration of hydrocarbons, allowing their accumulation.

3.1 Petroleum Formation

In short, petroleum is formed as follows:

Thermochemical reactions ---> Organic Matter ---> Kerogen ---> Hydrocarbon

Thermal maturation is the process through which the organic matter (kerogen) present in the reservoir rock is subjected to high temperatures and pressures over geological time, giving rise to hydrocarbons. The type of organic matter present in this sedimentary basin will determine what type of hydrocarbon will form (oil or gas) and their respective quantities. We will discuss this process in more detail later.

3.2 Classification of Petroleum Systems

Petroleum systems can be defined in three (3) types.

1- Known: There is a correlation between geological reserves and hydrocarbon accumulation.

2- Hypothetical: There is no correlation between geological reserves and hydrocarbon accumulation, although both are identified.

3- Speculative: It is assumed that there is an accumulation of hydrocarbons and source rocks, based only on geological evidence.

3.3 Sedimentary Basins vs. Petroleum Systems (Dynamics)

Within the dynamics of petroleum systems, according to the stratigraphic position of the salt layers (evaporites), petroleum systems can be classified into: post-salt petroleum systems and pre-salt petroleum systems.

Post-salt oil systems: Hydrogen hydroxide migrates above the salt layer through salt windows.

Pre-salt oil systems: Oil does not migrate above the salt layer due to the absence of salt windows, and drilling is done in this way.

4 SOURCE ROCK

These are fine-grained rocks (shales and limestones) whose organic matter, under certain suitable thermochemical conditions, can transform into hydrocarbons (oil and gas). They contain a high content of total organic carbon (TOC) and have very low permeability.

A source rock must have organic matter in adequate quantity and quality and be subjected to the stage of thermal evolution necessary for the transformation (or thermal degradation) of kerogen into hydrocarbons. It is generally accepted that a source rock should contain a minimum of 0.5 to 1.0% total organic carbon (TOC). The volumetric aspects of the source rock (thickness and lateral extent) should also not be ignored, as a rock with adequate quantity and quality of organic matter may, for example, be too thin to generate commercial quantities of hydrocarbons.

Shales are the most important types of hydrocarbon-generating rocks in the world.

Hydrocarbon generation depends on three main factors:

1) Presence of sufficiently rich organic matter to produce hydrocarbons.

2) Adequate temperature.

3) Sufficient time for the source rock to reach maturity.

4) Pressure and the presence of bacteria and catalysts also affect hydrocarbon generation.

Organic matter (in quantity and quality) deposited with sediments in sedimentary basins is converted by biochemical processes during burial into a complex organic polymer called kerogen, containing smaller amounts of nitrogen and oxygen than the original organic matter. This process is accompanied by the removal of water (H2O) and compaction of the sediments.

Kerogen is converted into hydrocarbons by thermal cracking (a chemical process responsible for breaking down larger molecules into smaller molecules) at high temperatures and pressures at great depths (Catagenesis).

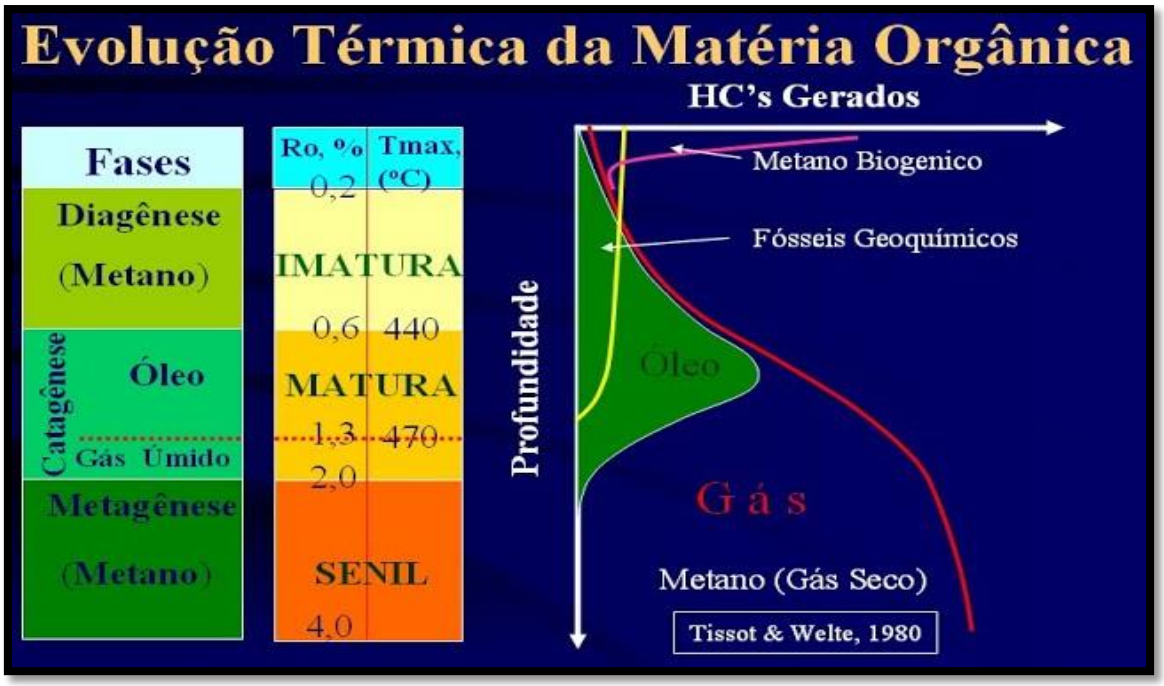
4.1 Kerogen Formation

There are three main phases:

1) Diagenesis: Immature kerogen (shallow depth) /50°C.

2) Catagenesis: Mature oil windows (greater depth)/250°C, depending on the literature.

3) Metagenesis: Along the mature gas window />250°C, organic matter is destroyed and forms methane gas and residual carbon (graphite).



4.2 Types of Maceral (kerogen identifiable microscopically)

1) The inertite group consists of carbonized remains formed by rapid oxidation under aerobic conditions (peat-producing environments). Low H/C and O/C ratios.

- Low H/C and O/C ratios
- Can generate dry gas, almost never forms petroleum.

2) Vitrinite is a preserved woody tissue derived from solidified humic gels.

- Moderate H/C ratio
- Can mainly generate Natural Gas

3) Exinite includes lipid-rich materials derived from leaves, spores, pollen, algae, vegetable waxes, resins, fats and oils.

• High H/C ratio. • Excellent generator of petroleum (liquid oil) and can also generate gas in advanced stages of maturation.

4) Liptinites are mainly derived from algal remains and generally have higher H/C ratios than exinites.

• Very high H/C ratio.

• Excellent generator of petroleum.

• Can generate heavy to light oil, depending on maturation.

• Subsequently generates gas.

The lower the H/C ratio, the lower the kerogen's potential to form petroleum and the greater the tendency to generate gas. The higher the H/C ratio, the greater the potential to generate petroleum because they have sufficient hydrogen to form long chains (liquid).

For a source rock to produce oil or gas, it is not enough to have organic matter. It needs: Adequate temperature, adequate pressure, and sufficient geological time. The time factor is fundamental because the chemical reactions that transform kerogen into hydrocarbons are slow.

Even if the temperature is ideal, if there is not enough time, the rock does not reach maturity.

• Too little time → immature kerogen → does not generate petroleum.

• Sufficient time → enters the oil window → generates oil.

• More time and more maturation → enters the gas window → generates gas.

That is, thermal maturation depends on temperature + time (thermal history of the basin).

4.3 Classification Regarding the Maturation of Organic Matter

• **Immature rocks:** Inadequate thermochemical conditions to generate hydrocarbons.

• **Mature rocks:** Adequate thermochemical conditions to generate substantial quantities of hydrocarbons.

• **Senil rocks:** Excessive conditions for oil generation, greater condition for gas generation.

4.4 Factors that control the preservation of organic matter

The main factor controlling the preservation of organic matter is the amount of oxygen.

The lower the amount of oxygen present in the sediments, the more suitable these sediments are to become potential hydrocarbon source rocks. Therefore, marine and lacustrine sediments are the most suitable to potentially become source rocks.

4.5 Main anoxic environments for hydrocarbon generation

• Restricted marine basins.

• Lakes with deep stratification.

• Zones of minimal oxidation (Deltaic environments with rapid burial and marine platforms with high organic productivity).

5 PETROLEUM GEOCHEMISTRY

In the previous chapter we talked about source rocks, but something that wasn't explained is how petroleum geologists know if a rock is a source rock or not? To answer this question, we will have to resort to petroleum geochemistry.

5.1 Petroleum Geochemistry

Petroleum geochemistry is a branch of organic geochemistry that studies the chemical composition, origin, migration, and accumulation of hydrocarbons. It analyzes rock and fluid samples to characterize the source rock potential and track the path of oil, optimizing exploration. It is crucial for determining the quality of petroleum and understanding its evolution.

One of the main objectives of petroleum geochemistry is to characterize the source rock potential (organic matter) and monitor migration routes, mapping the source rock-oil correlation.

5.2 Types of Samples Used

- Gravel Sample.
- Core Sample
- Outcrop Sample

5.3 Parameters Obtained to Characterize Petroleum Geochemistry in Laboratory Analyses

When we talk about parameters to characterize petroleum geochemistry in laboratory analyses, techniques such as Rock-Eval pyrolysis that measure parameters such as (Total Organic Carbon (TOC), Hydrogen Index (HI), Oxygen Index (IO), S1, S2, S3 and Tmax), API and vitrinite reflectance.

5.4 Rock-Eval Pyrolysis

Rock-Eval pyrolysis is a fast and efficient geochemical technique for evaluating the potential of petroleum source rocks, measuring the quantity, quality and maturity of organic matter.

The sample is heated in an oven at 600°C for 20 minutes, releasing free hydrocarbons (S1), generating potentials (S2) and CO2 (S3), allowing the calculation of indices such as HI, OI and Tmax.

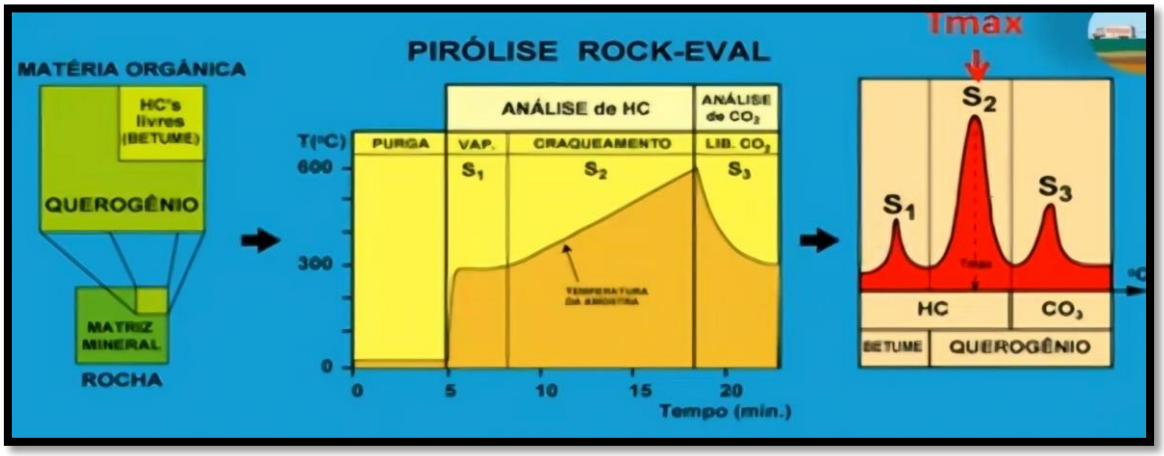
5.4.1 Main Parameters and Results

S1 (Free Hydrocarbons): Represents the oil/gas already generated and existing in the rock.

S2 (Generation Potential): Indicates the amount of hydrocarbons that the organic matter can still generate (mg HC/g Rock).

S3 (CO3 released): Measures the CO3 generated during pyrolysis, reflecting the oxygen content of the kerogen.

T.max (Maximum temperature): Defines the thermal maturity of the organic matter; higher values indicate greater maturity.



Analysis of Total Organic Carbon (TOC): Of the organic matter, a minimum of 1% TOC is required for Shales and 0.5% TOC for Calcilutites, however, the Source Rocks of greatest interest always present TOC > 3%.

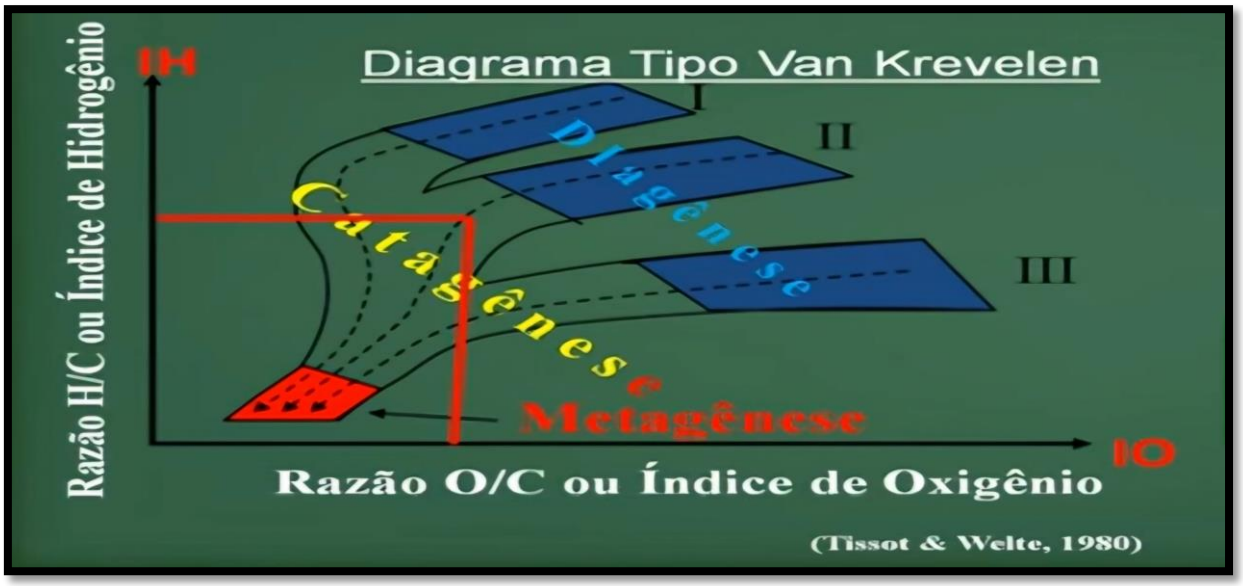
Through pyrolysis and TOC (Total Organic Carbon) we obtain the quality of organic matter, which is evaluated based on the Hydrogen Index (HI) and Oxygen Index (OI) using the Van Krevelen diagram.

• Diagenesis (immature).

• Catagenesis (being formed).

• Metagenesis (almost senile, burned).

The higher the HI and the lower the OI, the better the quality of the organic matter.



5.5 Kerogen Classification

Kerogen is generally classified into four types, based on H/C and O/C ratios (Van Krevelen diagram):

Type I kerogen (sapropelic): exhibits a high H/C (atomic) ratio (>1.25) and a low O/C (atomic) ratio (<0.15). It is rich in lipids, especially long-chain aliphatic lipids, and has a high petroleum-generating potential. It is mainly derived from the remains of algae and bacteria, frequently deposited in aquatic or estuarine environments.

Summary: Type I organic matter (kerogen) occurs in lake and marine environments and has a high hydrocarbon-generating potential (85% to 90%) to generate petroleum.

Type II Kerogen (planktonic): the most common type, it has intermediate H/C (<1.25) and O/C (<2.0) ratios. It is mainly derived from planktonic and bacterial remains deposited in marine environments (although remains of higher plants may also contribute). Due to its marine origin, it is often rich in sulfur. Its lipid content and oil generation potential are slightly lower than that of Type I kerogen. It tends to produce a mixture of gas and oil.

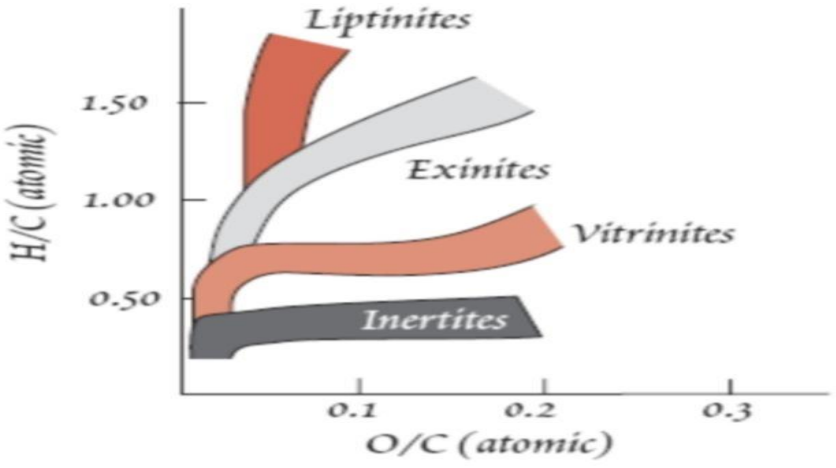
Summary: Lacustrine, Marine or mixed, intermediate potential to generate Oil and Gas (65% to 70%).

Type III Kerogen (Humic): has low H/C ratios (<1) and high O/C ratios (<0.3). It is rich in aromatic structures and poor in aliphatic structures. It is formed mainly from the remains of vascular plants. Its potential for oil generation is low, but it can be a source of gas (particularly methane) and coal.

Summary: Continental Lacustrine, low generating potential, but can mainly generate Gas (30% to 35%).

Type IV Kerogen (residue): has a low H/C (atomic) ratio (<0.5) and a low O/C (atomic) ratio (<0.3). Type IV kerogen mainly contains decomposed organic matter in the form of polycyclic aromatic hydrocarbons. It has no potential to produce hydrocarbons.

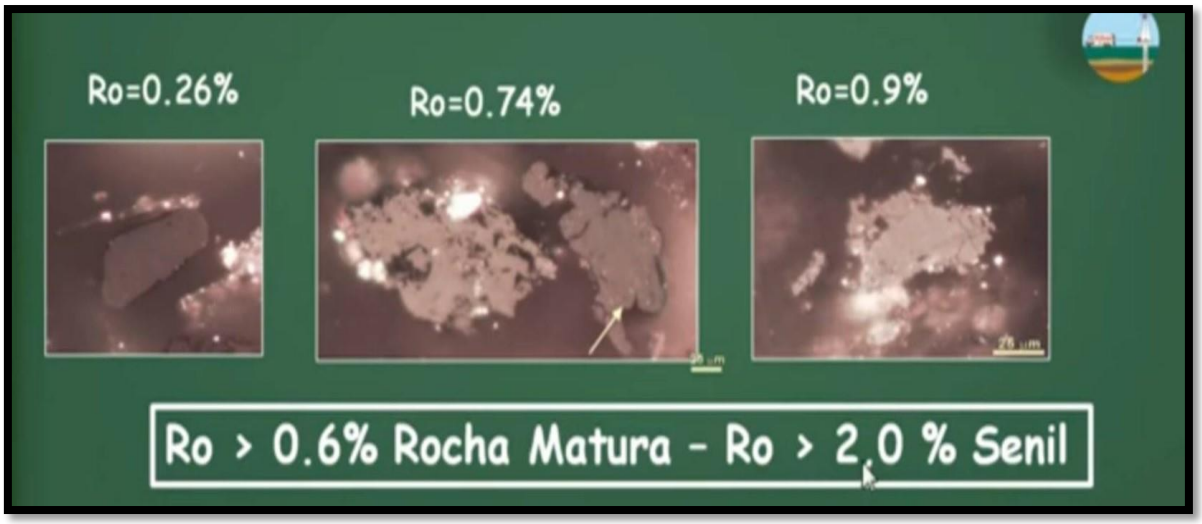
Summary: It has no potential to generate hydrocarbons.



5.6 Vitrinite Reflectance

Vitrinite reflectance is the percentage of light reflected (under a microscope) by vitrinite macerals in sedimentary rocks, used to measure the thermal maturity of organic matter. Fundamental in oil and coal exploration, it indicates the maximum temperature reached, correlating with hydrocarbon generation.

- If Ro <0.6% ---> Immature Rock
- If Ro >0.6% ---> Mature Rock
- If Ro >2% ---> Senile Rock



5.7 Spore Color Index (SCI)

The Spore Color Index (SCI) assesses the thermal maturation of rocks.

- If SCI < 4: Immature.
- If SCI > 4: Mature.
- If SCI > 8: Senile.

5.8 Biomarkers

These are geochemical fossils that preserve the structure of organic matter. They are highly resistant to temperature increase and biodegradation.

Information Generated by Biomarkers

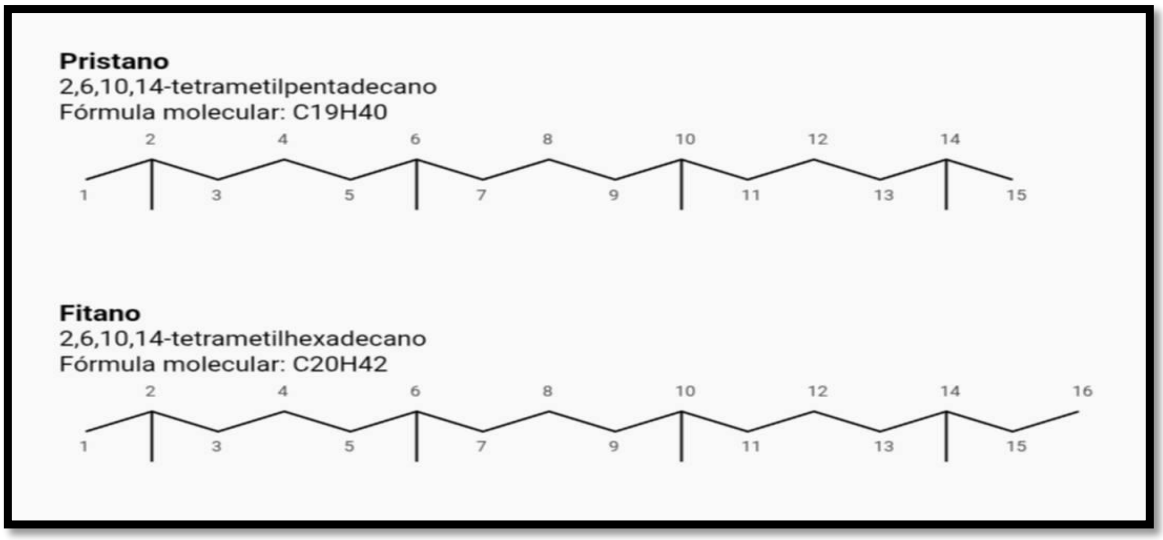
• Origin of Organic Matter (Marine or Continental).

• Stage of Thermal Maturation.

• Migration Routes (Oil/Oil and Oil/Source Rock Correlation).

Note: The migration route will allow establishing a parallel between oils, implying or not a common source rock for both (they serve to identify the source rock that generated a given hydrocarbon accumulation).

5.8.1 Types of Biomarkers (Pristane and Phytane)


Pristano
2,6,10,14-tetrametilpentadecano
Fórmula molecular: C19H40
2 4 6 8 10 12 14
1 3 5 7 9 11 13 15
Fitano
2,6,10,14-tetrametilhexadecano
Fórmula molecular: C20H42
2 4 6 8 10 12 14 16
1 3 5 7 9 11 13 15

Pristane and phytane are isoprenoid hydrocarbons (branched alkanes) used as biomarkers in organic geochemistry to identify petroleum sources, maturation, and depositional conditions (oxygenated or anoxic).

• High Pristane/Phytane ratios indicate source rocks with a higher percentage of terrestrial organic matter.

• Low Pristane/Phytane ratios indicate source rocks with a higher percentage of marine organic matter.

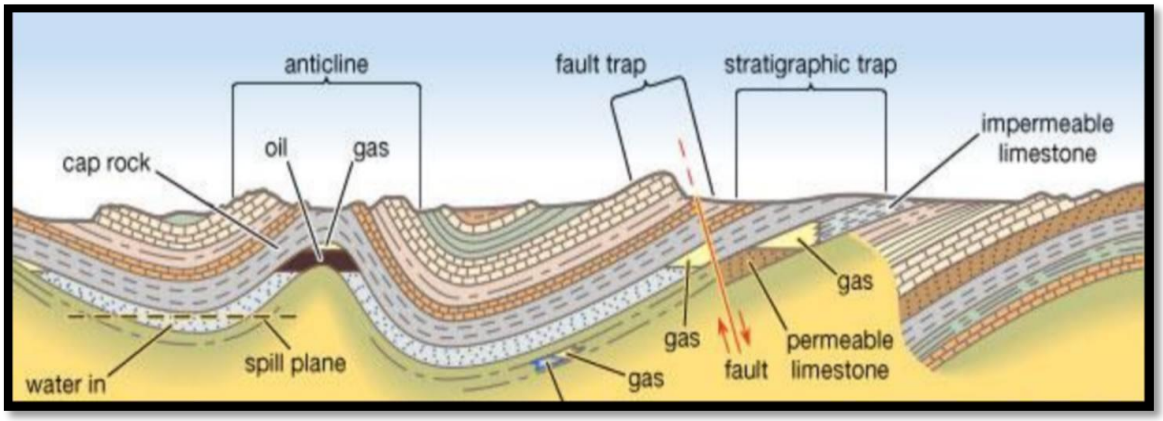
6 PETROLEUM MIGRATION

6.1 Types of Migration

• Primary (within the source rock).

• Secondary (as soon as it enters the reservoir rock).

• Remigration (when a trap is opened and the oil migrates to the surface).



6.1.1 Primary Hydrocarbon Migration

Primary migration occurs in the source rock during catagenesis, after the formation of kerogen in diagenesis. With the progressive increase in temperature, the kerogen undergoes thermal cracking, resulting in oil and gas. The generation of these hydrocarbons causes an increase in volume and internal pressure, leading to the formation of microcracks that allow the expulsion of the hydrocarbon from the source rock.

6.1.2 Secondary Hydrocarbon Migration

Secondary migration is the process of displacement of hydrocarbons after their expulsion from the source rock (primary migration). Once outside the source rock, oil and gas begin to move through porous and permeable rocks, such as sandstones, fractured limestones, or other sedimentary units with good pore connectivity. During secondary migration, hydrocarbons can move along carrier rocks, which act as transport pathways, or within reservoir rocks, which, in addition to transporting, can store fluids through faults, fractures, and unconformity surfaces, which can act as structural conduits.

The process continues until the hydrocarbons encounter a geological trap, associated with an impermeable sealing rock, where they are retained and accumulated, forming an economically exploitable reservoir.

This movement occurs mainly due to three fundamental factors:

• Pressure gradient – fluids move from zones of higher pressure to zones of lower pressure.

• Buoyancy (upthrust force) – as hydrocarbons are less dense than formation water, they tend to migrate vertically to higher levels of the basin.

• Capillarity – controls the entry and retention of hydrocarbons in the pores of rocks.

6.1.2.1 Long-Distance Migration

Long-distance migration is a concept within secondary migration, which describes the movement of hydrocarbons over significant geological distances until they find a suitable trap. That is, it is not limited to a few meters or tens of meters within a layer; it can travel kilometers within the petroleum system.

6.1.2.2 Short-Distance Migration

Short-distance migration occurs soon after the generation of hydrocarbons, within or near the source rock, traveling only short distances, usually a few meters to tens of meters. More concisely, short-distance migration is a type of secondary migration that occurs when the distance between the source rock and the accumulation is short. A practical example is the reservoirs observed in many areas of the Middle East.

6.1.3 Hydrocarbon Remigration

Remigration is a type of late secondary migration that occurs when a previously formed accumulation is disturbed by tectonic events, such as fault reactivation or seal faulting, allowing hydrocarbons to escape and migrate again, possibly being retrapped in a new trap or redistributed in the petroleum system.

7 RESERVOIR ROCK

A reservoir is defined as a rock with porosity and permeability suitable for the accumulation of petroleum. Most known reserves are found in sandstones and carbonate rocks, although oil accumulations also occur in shales, conglomerates, or even in igneous and metamorphic rocks.

7.1 Porosity and permeability

Porosity, represented by the Greek letter φ, is defined as the percentage (by volume) of voids in a rock, that is, it measures the fluid storage capacity and relates the volume of voids in a rock to the total volume of the rock.

In most reservoirs, porosity varies from 10 to 20%. Absolute porosity corresponds to the total volume of voids, while effective porosity refers only to the pores connected to each other.

Absolute porosity = Volume of Voids / Total Volume of Rock

Effective porosity = Volume of interconnected voids / Total volume of rock

Reservoirs typically exhibit horizontal and vertical variations in porosity. The quantity, size, geometry, and degree of connectivity of the pores directly control the productivity of the reservoir.

7.1.1 Methods for Obtaining Porosity

- Measured directly, in core samples.
- Measured indirectly, through electrical logs (diagraph logs).

The porosity of a rock can be classified as insignificant (0-5%), poor (5-10%), regular (10-15%), good (15-20%), or very good (>20%).

7.1.2 Types of Porosity

Primary (or depositional) porosity: Formed during sediment deposition, it can be intergranular or intragranular. This type of porosity tends to decrease with burial, due to the effect of mechanical compaction and diagenesis.

Secondary porosity: Secondary porosity forms after deposition, usually as a result of mineral dissolution.

Primary porosity is more common in sandstones, while secondary porosity occurs more frequently in carbonate rocks. Fractures can considerably increase the volume of voids in rocks. In sandstone and carbonate reservoirs, fractures can contribute to increased connectivity of

pores, while in shales, igneous rocks, and metamorphic rocks, these rocks account for almost all porosity.

7.2 Permeability

Permeability, usually represented by the letter K, is the rock's ability to transmit fluid, expressed in Darcys (D) or millidarcys (md). A rock has a permeability of 1D when it transmits a fluid with a viscosity of 1 cP (centipoise) at a flow rate of 1 cm^3/s, through a 1 cm^2 section and under a pressure gradient of 1 atm/cm.

Controlled mainly by the quantity, geometry, and degree of connectivity of the pores, the permeability of a rock is measured directly in core samples and can be classified as low (<1 md), regular (1-10 md), good (10-100 md), very good (100-1000 md), and excellent (>1000 md). Most reservoirs have permeabilities from 5 to 500 md.

Permeability is rarely the same in all directions in a sedimentary rock, generally being greater horizontally than vertically. Since it is inversely proportional to the viscosity of the fluid, the permeability of a reservoir for gas is much greater than for oil. Thus, while a reservoir can produce gas with only a few millidarcys, at least tens of millidarcys are needed for oil production.

When more than one fluid shares the pore space (as is the case with reservoirs containing water, oil, and/or gas), each fluid has a relative permeability, which varies depending on its saturation. That is, permeability is maximum (absolute permeability, Ka) when a fluid occupies 100% of the pores, and decreases (relative permeability, Kr) as this fluid shares the pore space with another fluid. A minimum saturation is required for a fluid to be able to flow. In the case of oil, a minimum saturation of around 20% is required for it to flow (Kr>0).

7.3 Abundance of Reservoir Rock Types

In sedimentary basins, sandstones comprise approximately 50-60% of reservoir rocks, carbonates approximately 30-40%, and other rock types approximately 5-10%.

Regarding hydrocarbons by rock type (worldwide), sandstones comprise approximately 50-70% of hydrocarbons in reservoir rocks, carbonates approximately 20-40%, and other rocks approximately 5-10%.

7.4 Types of Reservoirs

There are several types of hydrocarbon reservoirs, including:

Conventional reservoirs, where hydrocarbons can be extracted by primary or secondary processes, are porous and permeable reservoirs.

- Sandstones (porous and permeable).
- Carbonates (porous and permeable).

Unconventional reservoirs, which have petrophysical characteristics that make it impossible for hydrocarbons to be extracted by simple processes, i.e., they require more advanced technologies for their extraction.

Types of Unconventional Reservoirs:

- Shales - source rocks and reservoirs.
- Tight sands.
- Tight carbonates.
- Coalbed methane.
- Gas hydrates.
- Heavy oil reservoirs.
- Heavy oil.
- Tar sands.
- Unconventional gas reservoirs (shale gas, tight gas, etc.)

8 SEALING ROCK - CAP ROCK

Sealing rock (Salt) is any impermeable or low-permeability formation that can retain oil, gas, or water, preventing it from migrating to the surface. Typical caprocks are compacted schists, evaporites, and firmly cemented sandstones and carbonate rocks.

In simpler terms, we can say that sealing or capping rocks are responsible for retaining oil in traps. They must have low permeability associated with high capillary pressure in order to prevent the vertical migration of oil. Evaporites (especially halite) are the most efficient cappers, although shales are the most common in oil accumulations.

Shales can, in cases where the capillary pressure is not high enough, act as selective cappers, preventing the passage of oil and allowing gas to escape from the trap.

It should be noted that the sealing capacity of a rock is dynamic. A cap shale can, with increased compaction and some tectonic activity, break apart and lose its sealing capacity.

For the formation of an oil reservoir to be possible, it is essential that the formation of the trap be contemporaneous with or prior to the generation and migration of oil.

A trap is an underground rock formation that blocks the movement of oil and causes it to accumulate in a reservoir that can be exploited.

8.1 Classification of traps

- Structural traps.
- Stratigraphic traps.
- Salt dome traps.
- Hydrodynamic traps.
- Combined traps (structural trap + stratigraphic trap).

8.1.1 Structural Traps

Structural traps are those whose geometry is the result of tectonic activity, being related to faults, folds, or diapirs. Anticlines associated with reversible or normal faults are specific to the most common type of structural trap.

a) Folding trap: A folding trap is formed by syn- or post-depositional processes that deform geological surfaces into a curved or non-planar arrangement. The classes proposed in the fold trap regime are monoclinal, dome, nose, anticline, and syncline.

b) Fault trap: Fault traps are formed by the movement of rocks along a fault line. In some cases, the reservoir rock has moved in the opposite direction to an impermeable rock layer. The impermeable rock therefore prevents the escape of oil. In other cases, the fault itself can be a very effective trap. The classes proposed in the fault trap regime are normal and reverse faults.

c) Fractured trap: There are two types:

• Oil is trapped in the fracture porosity below an unconformity.

• Oil is trapped in the fracture porosity adjacent to the fault plane.

8.2 Stratigraphic Traps

Stratigraphic traps are those resulting from lithological variations, which can be of depositional origin (e.g., reefs, sandstone lenses, etc.) or post-depositional origin (e.g., truncations, diagenetic barriers, etc.).

Two main groups can be recognized:

a) Primary stratigraphic traps: result from variations in the facies that developed during sedimentation. There are four main types:

• Primary thinning of strata, for example, strata that disappear towards the top of the structure in less permeable rocks, such as shale.

• Isolated sandstone fluvial channels surrounded by impermeable shale.

• Submarine channels and sandstone turbidites in shale-rich strata.

• Porous reefs surrounded by shale, etc.

b) Secondary stratigraphic traps: result from variations that developed after sedimentation, mainly due to diagenesis. Many secondary stratigraphic traps

are controlled by unconformities, and are therefore called unconformity traps.

There are two types of unconformity traps:

• Oil trapped below the unconformity: Oil trapped below the unconformity in paleotopographic elevations below transgressive shales.

• Oil trapped above the unconformity: Oil trapped above the unconformity in paleotopographic depressions formed by porous channel sands.

8.3 Salt Domes

Salt domes form when salt is less dense than the overlying rock and moves slowly upward due to its buoyancy. For this to happen, there must be a minimum overburden and the thickness of the salt deposits must be greater than ~100 m. The upward movement of salt through sedimentary strata and the associated deformation are called halokinetic or salt tectonics. The movements can continue for several hundred million years.

Traps can form (1) in the strata covering the salt dome, (2) on top of the salt domes, (3) in the strata that curve upward against the salt intrusion, (4) due to stratigraphic compression of the strata surrounding the salt.

8.4 Hydrodynamic Traps

If the flow of intermediate waters in a sedimentary basin is strong enough, the oil-water contact can deviate from the horizontal due to the hydrodynamic shear stress that is established. In some cases, oil can accumulate without closure, that is, hydrodynamic traps form in zones where the downward flow of water retains the oil without any type of structural closure or stratigraphic barrier.

8.5 Combined Traps

Mixed traps are the result of the combination of two of any of the situations mentioned above.

9 SEDIMENTARY BASIN

A sedimentary basin is a low-lying area in the Earth's crust, of tectonic origin, where sediments accumulate. Source rocks, reservoirs and seals are found in the sedimentary basin.

The width and length of the sedimentary basin should not be less than 10 and 100 km, respectively.

There are six sedimentary basins in Angola. The main coastal basins are the Lower Congo Basin, the Kwanza Basin, the Namibe Basin, and the Benguela Basin. Inland, the Kassanje Basin and the Etosha-Okavango Basin stand out.

9.1 Formation Methods

It is common to categorize sedimentary basins according to the perceived formation method, creating groups such as:

• Foreland basins (caused by lithospheric bending).

• Back-arc basins (caused by lithospheric stretching).

• Separation basins (caused by lithospheric deformation).

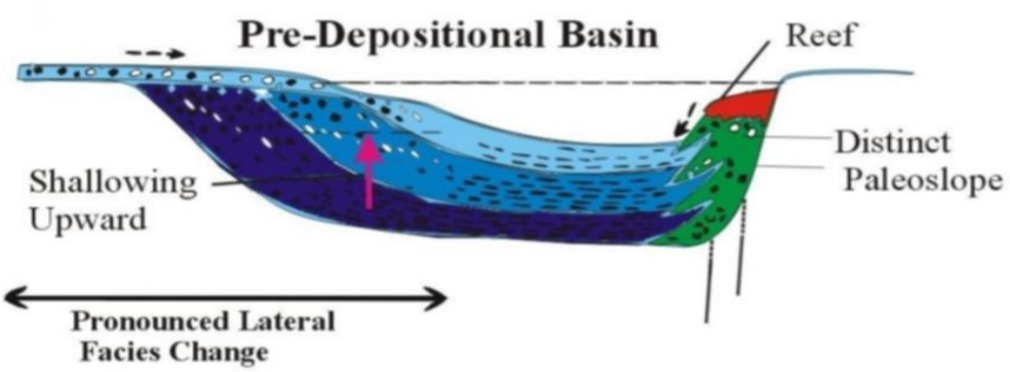
The mechanisms of formation of sedimentary basins are numerous and

often fundamentally linked to the concepts of plate tectonics.

9.2 Types of sedimentary basins

There are three types, namely, pre-, syn- and post-depositional basins.

1) Pre-depositional basins: Rapid tectonic movements precede significant sediment accumulation and create a morphological basin. The water depth in the basin decreases over time.

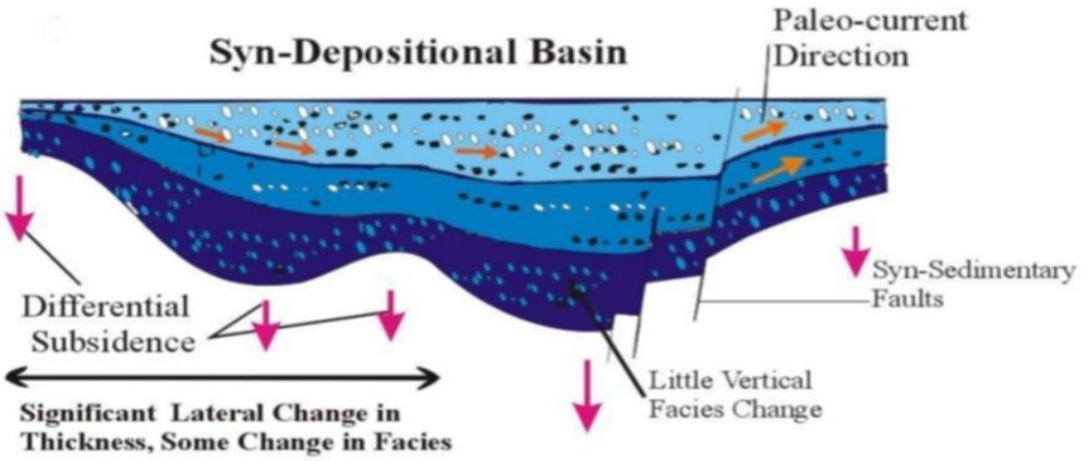


2) Syn-depositional basins: Sediment accumulation is affected by syn-depositional tectonic movements. The thickness of the sediments increases towards the center of the basin. In simpler terms, in a syn-depositional basin, tectonic movements occur at the same time as sediments are being deposited, that is:

• Tectonics are already active while sediments accumulate.

• The bottom of the basin gradually sinks.

• For this reason, there is more space to accumulate sediments in the center, resulting in a greater thickness of sediments towards the center of the basin.



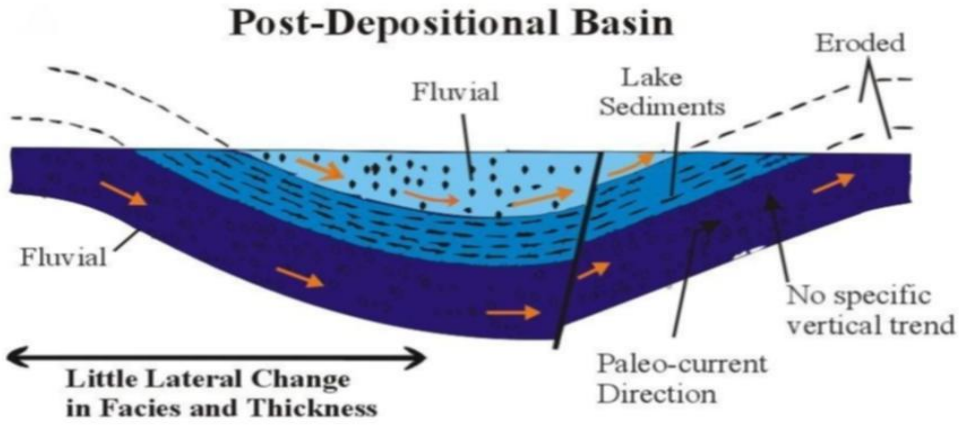
3) Bacias pós-deposicionais: A deposição de sedimentos antecede em grande parte os movimentos tectónicos formando uma estrutura de bacia. Assim, existe pouca ou nenhuma relação entre o transporte, distribuição e fácies destes sedimentos e a estrutura da bacia posteriormente evoluída, ou seja:

• Primeiro, os sedimentos foram transportados e depositados.

• Depois, realizaram movimentos tectónicos que deformaram a região e formaram a bacia.

Por este motivo, a forma final da bacia não controlou onde e como os sedimentos se depositaram.

In even simpler terms, the sediments didn't "know" that a basin would exist there, because it only formed later.



9.3 Difference between Syn- and Post-Depositional Basins

The Difference between Syn- and Post-Depositional Basins

Post-Depositional Basin

• Continental, paralic, and deep marine sediments appear distributed without following the shape of the basin.

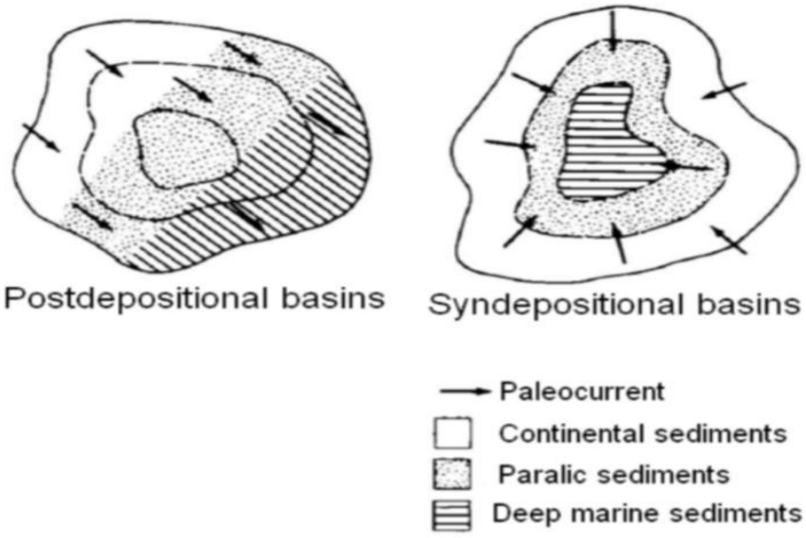
• Paleocurrents indicate transport directions independent of the current basin structure, showing that a basin formed after deposition, i.e., tectonics did not influence the distribution of sediments.

Syn-Depositional Basin

• Sediments are organized concentrically: continental at the edges, paralic in the middle, and deep marine in the center.

• Arrows (paleocurrents) point towards the center of the basin, showing that sediments accumulated where the bottom sank, demonstrating that tectonic influence directly affected deposition, controlling the thickness and distribution of facies.

The main difference between syn- and post-depositional basins is shown in the following figure.



The figure shows that:

Post-depositional → Tectonics did not control sedimentation.

Syn-depositional → Tectonics directly controlled where and how sediments were deposited.

9.4 Geomorphological Classification of Sedimentary Basins

Geomorphologically, sedimentary basins can be subdivided into basins, inlets, and troughs.

1) Basins have a saucer shape and a subcircular plan. They are shaped like a bowl or plate (saucer-shaped) and are generally almost circular when viewed from above.

Ex.: a round depression where sediments accumulate in the center.

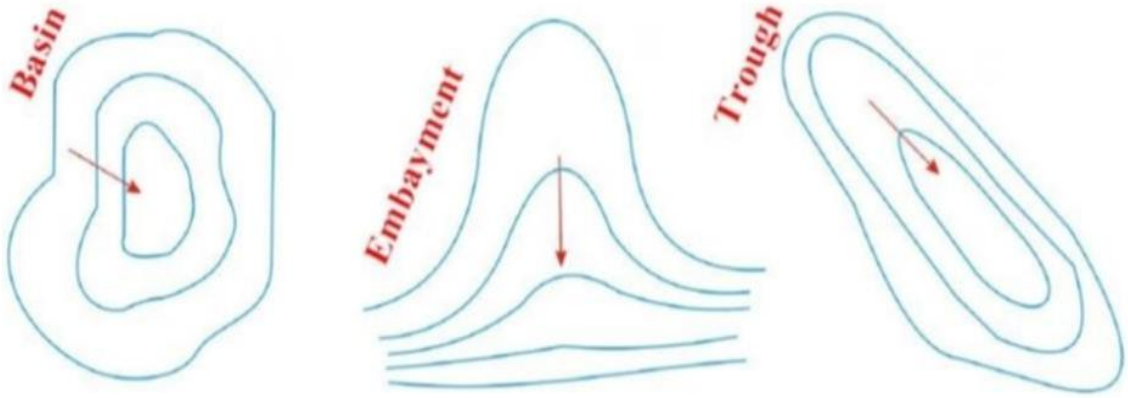
2) Inlets are areas that are not completely structurally closed,

but open into a deeper area.

Ex: a basin that connects to a larger or deeper area.

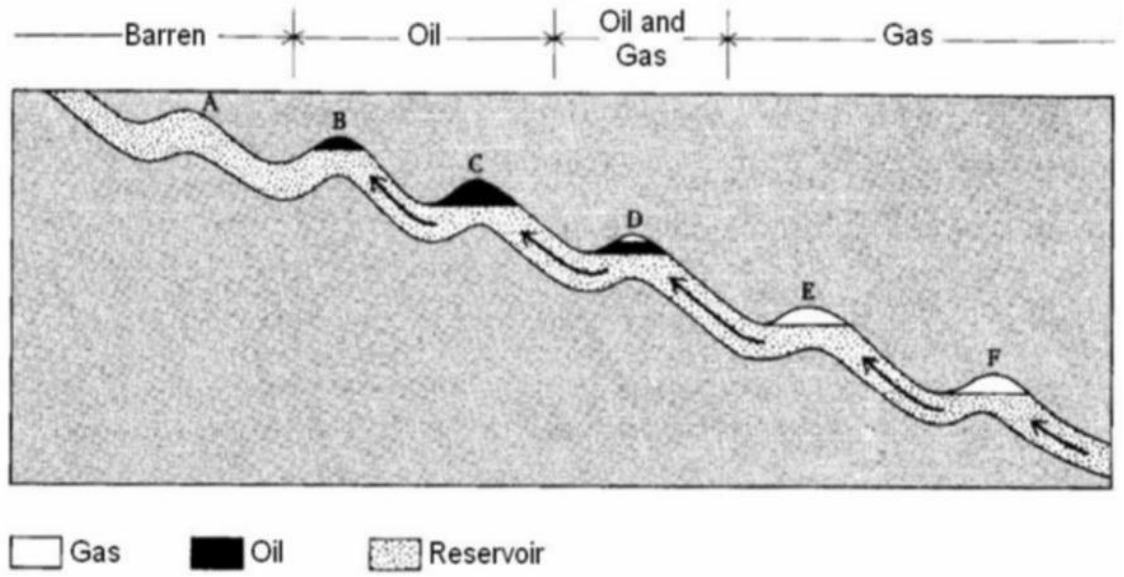
3) Troughs are linear basins.

Ex: an elongated valley where sediments accumulate following the line of the furrow.



9.5 Hydrocarbon Distribution within the Basin (Gussow's Principle)

This image illustrates Gussow's Principle (also known as Differential Spillover Theory), which is fundamental in petroleum geology to explain how oil and gas are distributed in a series of interconnected traps.



In summary, the lower part of the image attempts to explain the segregation and secondary migration of hydrocarbons along a basin. Here are the main points:

The Spill Mechanism: The principle assumes that:

• Hydrocarbons migrate from deeper areas of the basin to shallower areas. Because gas is less dense than oil, it always occupies the top of the trap first.

• When a trap becomes full of gas, the oil is "pushed" down until it reaches the spill point.

• Once this point is reached, the oil spills over to the next higher structural trap.

10. MAP OF THE MAIN SEDIMENTARY BASINS OF ANGOLA